COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Massachusetts Electric
A NEES company

Investigation by the Department of Public Utilities upon its own motion commencing a Notice of Inquiry/Rulemaking, pursuant to 220 C.M.R. §§ 2.00 et seq., establishing the procedures to be followed in electric industry restructuring by electric companies subject to G.L. c. 164	)	D.P.U. 96-100

COMMENTS BY
MASSACHUSETTS ELECTRIC COMPANY

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MASSACHUSETTS ELECTRIC COMPANY
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I. Introduction.

Massachusetts Electric Company's comments on the Department's May 1, 1996 order and proposed rules ("Order") are sponsored by Jeffrey D. Tranen and Richard P. Sergel, both Senior Vice Presidents of the New England Electric System ("NEES"), the parent company of Mass. Electric. Mr. Sergel is also the Chairman of Massachusetts Electric Company ("Mass. Electric"). The comments describe how the Department's proposed rules, together with the final rules adopted by the Federal Energy Regulatory Commission ("FERC") in Order 888, will affect Mass. Electric's plan for implementing retail choice in its service territory. Mr. Tranen provides additional information and comment on the Department's proposals to establish an Independent System Operator ("ISO") and power exchange ("PE") as a part of ongoing NEPOOL reforms (Section II of the comments). Mr. Sergel addresses intrasystem transactions and the impact of the order on service to retail customers (Sections III and IV of the comments). David Lax and Paul F. Levy also provide the comments included in Appendix A on the key issues associated with the sale or spin-off of generating assets in Massachusetts. Finally, specific responses to other questions raised by the Department in its May 1 order are also attached as Appendix B.

As the Department recognizes, the introduction of retail choice in the electric utility industry affects the organization of the industry in several fundamental ways. First, utilities' relationships with each other and other power suppliers within the New England Power Pool

("NEPOOL") must change. Second, Mass. Electric's arrangements with its wholesale supplier of electricity must be totally reformed. Although the primary focus of the FERC order was on open access transmission, the order also set procedures for the early termination of wholesale requirements contracts upon payment of costs that would be stranded by the early termination. These procedures apply directly to Mass. Electric's all-requirements contract with New England Power Company ("NEP"), and are different from the proposal for the recovery of stranded costs in Mass. Electric's initial filing in this proceeding. Third, Mass. Electric's relationships with its own customers must be modified. FERC's Order 888 and the Department's Order both address the first two of these transactions. In addition, the Department's Order will affect Mass. Electric's relationships with its customers. Our comments address each of the transactions in turn. Our conclusions are as follows:

A. Regional Issues.

- Utilities and NEPOOL should be able to meet the Department's objectives for open transmission access and the creation of an ISO by January 1, 1998.

- The Department's objective for the creation of a spot market power exchange by that date is extremely unlikely. However, a clear and transparent market price for competitive services can be created by January 1, 1998.

B. Intrasystem Transactions.

- Within NEES, corporate and functional unbundling is well underway and will be complete by January 1, 1998.

- The functional division between Mass. Electric's distribution facilities and NEP's transmission facilities is consistent with FERC's and the Department's tests for jurisdictional separation and should be maintained.

- Divestiture of NEP's generation is not necessary to assure distribution access for Mass. Electric's customers on fair and nondiscriminatory terms, or to prevent abuses of market power by utilities, and divestiture may not be required either directly or indirectly as a condition to stranded cost recovery.

C. Customer Issues.

- Unbundled rates for Mass. Electric can be implemented on a timely basis for customers. All customers should see unbundled prices in each bill.

Short term energy service pricing, such as that proposed in Boston Edison's E-Plan, should be implemented as an additional option under Mass. Electric's Flex Rate, but should not be required for all customers.

- Performance Based Rates should allow for company-specific determinations of productivity and exogenous factors and should be modified to maintain financial integrity and balanced incentives and rewards for utilities.

- Basic Service creates the potential for cross-subsidies and gaming, could require expensive metering and billing systems, and precludes the timely implementation of retail choice. These issues are avoided by the standard offer proposed by Mass. Electric.

II. Regional Issues: NEPOOL Reform.

A. Open Transmission Access: The Regional Transmission Group.

The Department and FERC both address the effects of open access on Pool operations. Both make clear that NEPOOL transmission services must be unbundled and provided to all eligible customers on a nondiscriminatory basis. FERC requires all tightly integrated power pools, like NEPOOL, to file a joint pool-wide open access tariff and to "begin to take service under that tariff for all pool transactions no later than December 31, 1996." (Order 888, pp. 270-71; 18 C.F.R. §35.28(3), at Order 888, pp. 783-84). The Department also recommends a "regional network tariff, including zoned rates with adders and subtractors to reflect constraints." (Order, p. 21). Both FERC (Order 888, p. 281) and the Department (Order, p. 21) clearly favor region-wide transmission arrangements that limit the pancaking of rates across individual utility systems.

The utilities in NEPOOL are addressing these concerns directly through the Regional Transmission Group ("RTG"). The current proposal for an RTG would provide both network and firm point-to-point service on a regional basis. The regional network service would be available to deliver connected resources of utilities on a firm basis, and to deliver energy on a nonfirm basis at no additional cost to transmission customers. This service would allow a transmission customer full and firm access to the generating entitlements necessary to serve load, and nonfirm access to daily or short term energy markets that is essential to create a New

England-wide short-term market for energy. The RTG network service contemplates that the transmission customer will also take network service from its local utility, and that the RTG network tariff will extend this local utility service over the regional network.

Because short-term energy sales under the RTG network tariff are not firm, the RTG proposes a second service -- firm point-to-point service -- to allow transmission of firm entitlements over the regional grid. Firm point-to-point service would be required before a new entitlement would receive credit against capability responsibility or any successor reliability requirement in New England. The point-to-point tariff would be structured with multipliers to encourage or discourage directional flows over restricted interfaces. This service would support a capacity market for New England.

Although the RTG does not contemplate the lease of transmission facilities to an independent operator, both the network and point-to-point services would require local utilities to dedicate transmission facilities to the RTG for transmission service under the regional tariffs. The RTG would then reimburse utilities for the costs of these facilities from funds collected under the RTG tariffs. Thus, the RTG as now contemplated would provide region-wide, non-pancaked transmission rates across New England, supported by dedicated facilities under the control of an independent governing body having open membership, and containing pricing provisions that signal the additional costs imposed on the system caused by transmission over limited interfaces. The RTG moves a significant distance toward the implementation of the Department's objectives for transmission as articulated in its May 1 Order. The firm deadline imposed by FERC should provide the impetus to bring those discussions to a timely and successful conclusion that is consistent with the Department's policy pronouncements.

B. The Independent System Operator.

We expect that the regional transmission tariffs being developed by the RTG will be administered by an Independent System Operator or ISO under a vote taken by the NEPOOL

Executive Committee on May 3, 1996. (Attachment 1). The creation of an ISO is designed to respond directly to the concerns raised by both the Department and FERC. Both agencies strongly encourage the formation of an ISO and provide guidance for its operation. (Order, pp. 13-17; Order 888, pp. 279-86). These reforms are now being undertaken within NEPOOL. Specifically, the NEPOOL reforms will create an ISO with independent governance and its own employees that will assume responsibility for the operational and settlement functions currently within the New England Power Exchange ("NEPEX") and for the administration of the RTG tariffs. As reflected in the vote of the NEPOOL Executive Committee, the ISO will:

> control the operations of the transmission system, the generation dispatch, and the implementation and administration as appropriate of the market settlement rules and regional transmission tariffs in an open and non-discriminatory manner and in accordance with current and future NERC and NPCC requirements.

Thus, the newly created ISO should meet the minimum requirements set forth in the Department's order. (Order, pp. 15-16).

C. The Power Exchange and Reserve Requirements.

Finally, the Department has suggested the creation of a power exchange or PE to create a viable "short-term pool for energy transactions" (Order, p. 22) at "clear and transparent spot market prices." (Order, p. 23). We have strongly supported the development of a bid-based, spot market pool within the New England region, and believe that it would facilitate the transition to a fully competitive market. However, our views have not yet prevailed within New England. As a result, the creation of a region-wide, spot market power exchange is not part of the current NEPOOL Plus plan, and is a more substantial task than the creation of an ISO. Specifically, the creation of a NEPOOL-wide, spot market power exchange will require the development of a much broader consensus within New England and will require substantial modifications to the NEPOOL billing systems. In addition, NEPOOL will need to address difficult contract issues, such as the rights of participants in jointly owned generating units and parties to unit contracts under a bid system of unit dispatch. These issues are unique to NEPOOL. They result from the

historical integrated dispatch within the Pool which has allowed several smaller utilities to gain entitlements in larger generating units. This joint participation of so many utilities in so many major power projects is unique and the resulting contract issues have not been encountered elsewhere in the world. Other practical difficulties are discussed in the response to the first question in Appendix B. These requirements prevent the implementation of a NEPOOL-wide, spot market power exchange by January 1, 1998.

The absence of a fully developed, spot market power exchange on the date that all customers are released to the market presents a significant impediment to a rational transition to retail choice. Simply stated, Mass. Electric cannot release one million customers to the market before a fully functioning market exists. The resulting customer confusion and dissatisfaction would undermine the transition. These effects can be avoided through a more orderly transition to the market. Our suggestion was incorporated in Mass. Electric's standard offer proposal.[1] Under that approach, customers are gradually moved to market. The market grows more slowly in a way that accommodates new entrants. A visible market price for electricity supply is created early in the transition, and stable pricing is maintained for customers who do not wish to enter the market right away.

The gradual and rational transition to the market would not impede competition; it would encourage it. The aggressive prices and new service options developed in the early stages of the New Hampshire retail competition pilot program in which about 30 suppliers are competing for 50 megawatts of load, demonstrate that competition will work even if introduced in small increments. Under the standard offer proposal, all customers would have choice and the

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[1]Other alternatives include postponing retail choice until a fully developed spot market power exchange is implemented throughout New England or developing a Massachusetts-only solution to a spot market power exchange. Neither of these options is attractive. The delay of retail choice until rules for a spot market are developed by NEPOOL and approved by FERC creates uncertainty for customers and the potential for an indefinite postponement of retail access. The alternative Massachusetts plan is as difficult if not more complex to implement than the New England-wide solution, because the issues associated with a spot market would all have to be resolved and then implemented consistently with the NEPOOL agreement.

suppliers in the market would all work very hard to encourage customers to choose their services. The transition to a competitive market would be quick, efficient, and orderly. The standard offer is a more workable solution than forced wholesale sales into and purchases from an undeveloped spot market power exchange.

Moreover, the marketers would create the "clear and transparent spot market prices" that the Department seeks. Price must be disclosed to make a sale. In the New Hampshire pilot program, prices are open and price competition is direct and vigorous. Suppliers are extolling the benefits of their own offerings and identifying the flaws in their competitors' proposals. Even on this limited scale, prices are becoming widely known and advertised. A similar but more extensive effort should be expected when the choice is introduced for all customers. At that point and even with the standard offer, there will be a vigorous market for power supplies and a clear and transparent market price.

Finally, as explained in our initial filing, the standard offer directly addresses the concern about the potential for double payment and monopoly pricing. If market prices increase after the introduction of retail choice, customers will be able to stay with the standard offer, and maintain price stability. They will receive value for their payment of the utility's fixed costs. The standard offer price cap will prevent excessive profits before the market is fully developed. The Department's concerns that the standard offer will give undue market power to incumbent utilities was also addressed by Professor Gilbert (supported by the report of Hartman and Tabors for the Attorney General), who found no evidence of undue horizontal market power in the New England generation market. To the extent that the Department is concerned about vertical market power, we believe that these concerns can be met through corporate unbundling and the standards of conduct for affiliate transactions as further discussed below. Moreover, the fixed price trajectory in the standard offer operates much like a performance based rate, and encourages the purchase or use of the most efficient power supplies available, regardless of their ownership. To the extent that the Department has unresolved concerns about the standard offer

proposal, Mass. Electric urges the Department to address them in the context of the standard offer, rather than by forcing a power exchange on an unworkable timetable.

Under either approach, the Department should not require an immediate reform of a supplier's obligations under the NEPOOL agreement. Those obligations should initially remain the same, but should be allocated to new suppliers based on their contracted loads. Thus, under either basic service or the standard offer, the NEPOOL reliability requirements should be applied consistently and should be fully internalized into the competitive market. These NEPOOL requirements may be modified in the future as the market develops. For example, in the new market, it may not be appropriate or efficient to assign reserve requirements by multiplying contracted load by a predetermined reserve margin. Market suppliers may develop other options that maintain reliability at a lower cost. NEPOOL is now evaluating alternatives to the reserve margin calculation that may produce more flexibility for suppliers to meet reliability criteria.

Regardless of the requirements that are developed, the rules should be applied to suppliers, and not to the ISO or distribution companies. By applying the rules to suppliers, the costs of meeting reliability requirements will be subject to the continuous pressure of the marketplace. The supplier who meets the rule most efficiently will thrive, and the supplier with a higher cost solution will have lower profits and fewer sales. This test is continuous and dynamic. The suppliers' solutions for meeting reserve requirements will be much more efficient than the direct acquisition of reserves by the ISO or the distribution company with the resulting costs recovered in the wires charge. Thus, by applying the rules to suppliers, all costs will be included in the market price component of the bill, the reliability obligation will be fully internalized, and each supplier's success in meeting the obligations will be fully and continuously tested against its competitors in the marketplace.

III. Intra-System Transactions.

In addition to NEPOOL reforms, industry restructuring focuses on the functional separation of operations within each individual utility. On our system, many of these functions are already performed by different corporate entities. Nevertheless, industry restructuring will require us to complete corporate and functional unbundling, terminate Mass. Electric's all requirements contract with NEP, and address divestiture issues. As with the NEPOOL transactions, these arrangements were addressed by both the Department in its order and by FERC in Order 888. FERC's Order 888 is particularly significant for the termination of the wholesale power contract because it sets forth the procedure for modifying NEP's contract with Mass. Electric to provide for its early termination and for the recovery of the resulting stranded costs.

A. Functional and Corporate Unbundling.

In their orders, both the Department and FERC endorse the functional unbundling of the generation, transmission, and distribution operations on the system. In Order 888, FERC concluded that "functional unbundling of wholesale services is necessary to implement nondiscriminatory open access transmission." However, FERC did not require corporate unbundling. (Order 888, p. 57). The Department went further and concluded that "functional separation is the minimum acceptable approach," and defined functional separation as the "creation of separate corporate entities (e.g., generation, transmission, marketing, and distribution subsidiaries) under one holding company." (Order, p. 26).

Mass. Electric and its affiliates are well under way to implementing the Department's recommendation. As a result of the holding company structure within NEES, Mass. Electric and its affiliates have long been unbundled to some extent, with a corporation for generation and transmission that is separate from Mass. Electric and the distribution affiliates serving customers in other states. We are now extending that functional unbundling by creating separate corporations for transmission and marketing. Thus, separate corporate affiliates will engage in

generation (NEP), transmission (NEES Trans), distribution (Mass. Electric in Massachusetts), and marketing (NEES Energy, Inc. in Massachusetts). This approach should comply fully with the Department's policy and be consistent with FERC's.

In addition, the Department and FERC agree on the jurisdictional division between transmission and distribution services. In Order 888, FERC reaffirmed its seven factor test for the separation of transmission and distribution facilities between state and FERC jurisdiction. (Order 888, pp. 403, 436-37). This same test was endorsed by the Department in its order. (Order pp. 18-19). We believe that the separation of facilities between Mass. Electric's distribution plant and the transmission facilities to be operated by NEES Trans is consistent with this seven factor test and provides a clear and workable jurisdictional separation between state and FERC responsibility.[2] If the Department and FERC agree, the jurisdictional separation between transmission and distribution facilities will have already been completed for Mass. Electric. As a result, the Department would continue to regulate the rates, terms, and conditions of Mass. Electric's distribution service to customers along substantially the same jurisdictional line that has been applied in the past.

Equally important, FERC and the Department agree that the functional definition of transmission and distribution facilities does not allow retail customers taking service at transmission voltage to bypass retail service including access charges and charges for low income, demand side, and renewable resource programs. (Order 888, p. 437; Order, p. 19). This agreement is fundamental to a successful restructuring. On our system, it simply means that Mass. Electric rather than NEES Trans will arrange for transmission and provide distribution services to all retail customers within Mass. Electric's service territory. In this respect, Mass.

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[2]FERC's seven factor test is set forth at page 403 of Order 888. Generally, the division between Mass. Electric's facilities and NEP's facilities occurs at the low side of the step down transformers from the 115 kV and 69 kV systems. Mass. Electric's purchases from NEP have generally been metered at these points. Under the current separation, Mass. Electric's ownership of facilities is consistent with the Department's test (Order, p. 20), which also defines transmission facilities as 69 kV or above.

Electric supports the Department's clear statement of policy on maintaining the integrity of distribution service territories. (Order, p. 40). The Department's approach to this issue and to the implementation of reverse metering under PURPA (Order, p. 41), will prevent gaming to avoid costs and charges expressly included in transmission and distribution rates as a matter of policy during the industry restructuring transition period.

B. Termination of Mass. Electric's All-Requirements Contract.

The more significant step toward retail choice involves the unbundling of NEP's wholesale rate and the termination of Mass. Electric's all requirements contract with NEP. This termination in turn triggers NEP's recovery of stranded costs from Mass. Electric. Specifically, Mass. Electric's wholesale power contract with NEP must undergo a substantial revision to comply with the regulations under FERC's Order 888. First, NEP must unbundle transmission from generation in its all-requirements rate under the FERC order. (Order 888, pp. 89-90). This element of the FERC order is consistent with the Department's requirement for utilities to file unbundled rates by October 7, 1996 and implement them in the first quarter of 1997. (Order, p. 52). With the creation of NEES Trans and the filing of new transmission tariffs in March, 1996, we are well on our way to meeting these unbundling requirements in a timely manner. Separately stated charges for transmission and power supply should be reflected in NEP's rates to Mass. Electric within the next few months, and those rates will, in turn, be reflected in Mass. Electric's filing with the Department.

Second, beyond unbundling of NEP's rate, to allow Mass. Electric's customers to exercise retail choice and for Mass. Electric to obtain power from other suppliers, the power supply portion of Mass. Electric's wholesale power contract with NEP must be terminated. At present, that contract requires seven years' advance notice of termination or of a change in power suppliers. Order 888, however, sets forth procedures for modifying these provisions to permit the early termination of the contract. (Order 888, p. 85). Specifically, FERC concluded that

Mass. Electric, as a customer under a wholesale requirements contract, could apply under Section 206 of the Federal Power Act to modify its contract, notwithstanding a contractual notice provision. (Id.) Any contract modification would be conditioned on the customer's payment of the wholesale supplier's stranded costs, which must be determined in the same proceeding. (Order 888, pp. 86-87). The calculation of stranded costs associated with the termination is set forth in some detail in Order 888 and in the FERC rule. (Order 888, pp. 598-620; 772-77). These procedures can be used to develop contract termination charges and remaining power supply arrangements between NEP and Mass. Electric so that Mass. Electric is in a position to implement retail choice by January 1, 1998 as required by the Department.

In its order, FERC reaffirmed its commitment to recovery of costs stranded as a result of open access. Specifically, the Commission found that (Order 888, p. 453): "If a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, we believe that the utility is entitled to recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer." In this case, the FERC ruling applies directly to the recovery of NEP's stranded costs from Mass. Electric. The procedures established in Order 888 for the calculation and recovery of NEP's stranded costs from Mass. Electric are different from the calculation proposed by Mass. Electric for stranded cost recovery in its filing to the Department. FERC has adopted a lost revenue approach to make that calculation, rather than the fixed cost approach proposed in Mass. Electric's filing. However, the ultimate objective of the two agencies is the same. As with the Department's policy, FERC's regulations are intended to provide a reasonable opportunity to recover net, non-mitigatable stranded costs. Moreover, FERC's Order contemplates a mutually acceptable resolution of the contract issues between the wholesale supplier and its customers.

Thus, under the FERC rule, NEP will bill Mass. Electric the appropriate termination charges, and Mass. Electric will, in turn, recover the actual FERC-approved termination charge in its access charge. Consequently, the Department's proposed rules for estimating stranded cost

recovery are unnecessary for Mass. Electric, because Mass. Electric's contract termination payments will be known and measurable. Under the law, the Department must accept the costs authorized by FERC as reasonable for Mass. Electric. Eastern Edison Co. v. Department of Pub. Utils, 388 Mass. 292, 302 (1983); Mississippi Power & Light Co. v. Moore, 487 U.S. 354 (1988). FERC will have already evaluated the reasonableness of NEP's termination charge, with due regard for mitigation through a market value credit or resale by NEP.

A disallowance of even a low percentage of NEP's termination charges will threaten Mass. Electric's financial integrity and ability to maintain reliable distribution service. As explained in our initial filing (Sergel, p. 16; Jesanis, pp. 18-19), disallowance of only 10 percent of NEP's proposed termination charge would impair Mass. Electric's ability to make interest payments to bondholders. Mass. Electric could not survive a disallowance at the level of 20 percent to 50 percent which would be tolerated under the Department's proposed rules. See 220 C.M.R. § 11.03(4). As we explained in the legal analysis made in our initial filing, such a disallowance would represent an unconstitutional taking of Mass. Electric's property. Moreover, the Department's proposal to require "sales and voluntary writedowns of assets" as a mitigation strategy (220 C.M.R. § 11.03(2) (definition of mitigation and § 11.03(3)(iii)(d)) does not work for Mass. Electric. A "voluntary writedown" does not create economic value or mitigate economic loss, it simply transfers that loss from customers to investors. In addition, as explained above, NEP is the company with the generating assets, not Mass. Electric. NEP's stranded costs and mitigation strategies will be evaluated by FERC in accordance with the procedures set forth in Rule 888. As discussed below, the Department has no statutory authority to require the sale of assets by NEP. Similarly, the Department has no jurisdiction to condition recovery of NEP's stranded costs on divestitures or writedowns. See Mass. Electric's Legal Commentary filed on February 16, 1996.

C. Divestiture of Generation.

The Department's proposed rules would encourage divestiture of generation by utilities. As explained above, the proposed rules would not apply in Mass. Electric's case. The ratemaking incentives proposed by the Department would not apply to NEP's termination charge, which is subject to FERC's jurisdiction, and Mass. Electric owns no generation to divest. Moreover, as the Department recognizes, it has no statutory authority to require divesture directly (DPU 95-30, p. 41, n. 31); it also lacks the authority to force divestiture indirectly through the imposition of a penalty on return or cost recovery for retaining generation.

Equally important, divestiture is not necessary to prevent anticompetitive affiliate transactions or to create a fair and competitive power supply market. Mass. Electric will provide fair and nondiscriminatory access to its distribution system whether or not NEP divests its generating assets. The corporate separation implemented on our system, the standards of conduct proposed by the Department and adopted as a final rule by FERC in Order 889, and the termination of the all requirements contract make divestiture unnecessary. The experience in the gas industry and to this point in the electric industry indicates that markets can develop fairly without divestiture. Moreover, the testimony by Professor Gilbert in our initial filing, the analysis in the Attorney General's comments, and Professor Gilbert's responses to the Department's questions that are included in Appendix B to these comments all demonstrate that divestiture is not necessary to address horizontal market power by utilities in New England. For all these reasons, the Department should not require utility divestiture of generation in its rules.

In any event, the Department should proceed carefully, as suggested by Dr. Lax and Professor Levy in Appendix A. The Department's approach to divestiture should be clear and flexible. In particular, the Department should allow utilities to put forth other valuation options such as a partial spin-off of generating company stock, in place of asset sales. Utilities who elect to determine the residual value of their generation through a market valuation should have the option of implementing any one of three methods: an asset sale, a complete spin-off to shareholders, or a partial divestiture through either a partial spin-off or initial public offering.

The first two methods would lead to a complete separation of generating assets from transmission and distribution assets. The third method creates a separate fiduciary obligation by the generating company to independent shareholders. In order to provide incentives for utilities to pursue a sale or spin-off option, the Department should make clear that the valuation obtained through the option selected by the utility will be treated as conclusive evidence of mitigation and that all net stranded costs resulting from that measurement of mitigation will be recoverable without discount or delay. The comments of Dr. Lax and Professor Levy in Appendix A expand on this point.

The Department's proposed incentives for divestiture do not meet these standards. They do not provide an affirmative signal to utilities, but rather impose a penalty for retaining existing generation. This approach is unlawful, unfair, inefficient and unworkable. Although the Department has the authority to approve asset sales by utilities, the Department lacks authority to force these sales, either directly or indirectly through conditions on the recovery of stranded costs. Moreover, forced divestitures are unlikely to produce the desired result -- a reasonable and fair transition to the market. On the contrary, forced sales may artificially depress prices, deprive customers of established suppliers and solid competitors in the market, eliminate the ability to implement the standard offer, and produce greater stranded costs and lower quality service for customers.

IV. Customer Issues.

The Department's proposals will also affect Mass. Electric's relationships with its customers in many significant ways. Under the proposed rules, Mass. Electric must unbundle its retail rates and implement spot pricing for energy services, develop a performance based rate plan and price capped rates, and create programs for basic and universal service. Each of these issues will be discussed in turn.

A. Unbundle Retail Rates.

The Department requires Mass. Electric to unbundle its rates in a filing to be made by October 7, 1996. (Order, pp. 50-52). Mass. Electric agrees that the unbundling filing will give valuable information to customers by separating the competitive component of the bill from the pricing for regulated services, and is prepared to make the filing on a timely basis. After the filing, customers will receive unbundled bills with discrete distribution, transmission, access, and generation components. The separate identification of the generation component on the bill will be a major step in aiding the customers' transition to market pricing.

The Department also suggests that utilities implement short-term energy services pricing similar to that proposed by Boston Edison Company in its E-Plan for the competitive power supply component of the customer's bill. Mass. Electric believes that variable energy pricing should be an option for customers, but should not be required for all customers. Mass. Electric already has in place a rate option for Flex Rate service under its G-5 rate. This rate option is designed similarly to the Boston Edison E-Plan rates, but bases prices on Mass. Electric's costs under NEP's wholesale rate rather than a short-term price index. Mass. Electric's Flex Rate could be expanded to include other pricing options. However, metering and billing costs preclude it from being made broadly available. If the Department seeks short run market pricing prior to actual retail choice, we suggest that the Department allow utilities to develop programs much like that already in place for Boston Edison to test different metering options, billing approaches, pricing protocols, and service alternatives. In this way, the early implementation of energy service pricing might provide a practical test for the implementation of spot market pricing using a short-term variable market price.

B. Performance Based Rates.

The Department also sets forth proposed rules for performance based ratemaking and price capped rates for distribution companies. (Order, pp. 71-76). The inflation index includes

an x-factor that includes components to reflect productivity adjustments, a customer dividend, an adjustment for accumulated inefficiencies, and an input price differential. (Order, p. 74). To be meaningful, these factors must reflect differences among the state's utilities. For example, a company, such as Mass. Electric, with a low starting point will have already realized more productivity offsets, paid customers' more dividends, and eliminated more inefficiencies in its operations than other distribution companies. It would be unfair and inappropriate to apply the same x-factors to Mass. Electric's lower starting point as the Department applies to other, higher cost utilities. The Department should either apply standardized starting points with standard x-factors, or apply different x-factors to the different starting points contemplated under the proposed rules. The Department should not penalize past efficiency gains through the application of standardized offsets to different starting points.

Moreover, the Department should recognize the fundamental importance of maintaining the financial integrity of the distribution company during the uncertain transition period. For example, Mass. Electric's projected construction expenditures over the next five years total $500 million. (Mass. Electric filing, Jesanis, p. 20). Other utilities may have to complete significant refinancings to implement the corporate reorganizations contemplated by the Department in its order. Solid financial statements are essential to minimize the costs of these financings and to allow the distribution company the resources to maintain quality service. Accordingly, the Department should shorten the period of the price cap plan, allow equity return caps and collars for distribution operations, balance the disallowances or penalties for substandard service with the potential for rewards for outstanding performance, and allow rates to increase at a level necessary to reflect all the factors that drive distribution costs, including ongoing construction requirements and the O&M expenses associated with maintaining reliability and improving power quality on the distribution network.

These steps will help establish and maintain the financial integrity of the distribution companies operating in the state. They will also assist in meeting accounting criteria necessary

to avoid a write off of the distribution company's regulatory assets under FAS 71. Those criteria require a reasonable assurance of continued cost-based regulation to maintain regulatory assets on the financial statements of the distribution company. The Department's PBR proposal does not provide that assurance and therefore raises serious questions as to whether distribution companies would be allowed to continue FAS 71 regulatory accounting. If not, Mass. Electric would be required to take a charge against earnings of approximately $50 million. The Department should modify its PBR proposal to avoid this result.

C. Basic Service.

The final issue focuses on utility service during the transition to open access in the market. Mass. Electric had proposed to ease the transition to the market for utilities and customers through the provision of a standard offer. The Department has included the standard offer as an option in the proposed rule, but suggests that basic service purchased through a spot market power exchange is a preferable alternative. (Order pp. 45-46). The basic service option as proposed by the Department presents several significant implementation issues. First, rate designs and availability limitations must be established to prevent cross-subsidies caused by selective switching. For example, a customer could game a basic service rate, which is designed using an average annual market price, by agreeing with a supplier to switch to basic service during higher cost summer months. Unregulated switching of this kind can lead to inappropriate cross-subsidies. Second, short term hourly pricing, which tends to eliminate this kind of gaming, will present significant metering and billing issues that must be resolved before hourly pricing can be extended to all customers. Third, basic service as proposed by the Department is premised on a short-term power exchange that is clearing all transactions, and thus the power exchange must be in place and operating efficiently prior to the extension of basic service to all customers. As explained above, an efficient power exchange is unlikely to be implemented by January 1, 1998. These practical challenges are significant, and could preclude the timely

introduction of retail choice. Finally, the involuntary assignment of customers from a fixed rate service to a potentially volatile spot price is likely to be unpopular with customers. Thus, the Department should retain the standard offer as an alternative for service in its proposals to introduce retail choice of power suppliers in Massachusetts.

V. Conclusion.

For the reasons stated here and in the appendices, the Department should modify its order and proposed rules to: (1) allow additional time to develop a power exchange; (2) implement the standard offer as an alternative to basic service; (3) eliminate the conditioning of full stranded cost recovery on divestiture; (4) develop short run pricing for energy services as a service option, not a requirement, and (5) implement a fair and balanced performance based rate plan that allows distribution companies to provide quality service and maintain their financial integrity during the transition to retail choice.